



**INDIANA  
MICHIGAN  
POWER®**

*A unit of American Electric Power*

**Indiana Michigan Power**

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Mr. David L. Hardy  
Chairman  
Indiana Utility Regulatory Commission  
Indiana Government Center South  
302 West Washington Street, Room E-306  
Indianapolis, Indiana 46204

May 12, 2006

Dear Chairman Hardy:

Re: Energy Policy Act of 2005

Enclosed is a courtesy copy of Indiana Michigan Power Company's (I&M) response to the Indiana Utility Regulatory Commission's data request and comments on the IURC Staff's White Paper regarding the Energy Policy Act of 2005. I&M's responses were also submitted to Dale Thomas via e-mail.

If you have any questions or comments regarding I&M's responses, please contact me at (260) 425-2119.

Sincerely,

Kent D. Curry  
Director of Regulatory Services

dsl

Enclosures

c: Dale Thomas - w/enclosures

**COMMENTS OF INDIANA MICHIGAN POWER COMPANY  
REGARDING THE FEDERAL ENERGY POLICY ACT OF 2005**

Indiana Michigan Power Company (I&M or Company) appreciates the opportunity to address Chairman Hardy's April 12, 2006 letter regarding the Energy Policy Act of 2005 (EPA05). I&M will be responding to the data request attached to Chairman Hardy's letter as well as commenting on the IURC Staff's White Paper on the five EPA05 standards; namely, Net Metering, Interconnections, Fuel Sources, Fossil Fuel Generation Efficiency and Time-based Metering and Communications. I&M's response will first offer introductory comments on the EPA05 standards and then turn to the specific data requests.

**INTRODUCTORY COMMENTS**

In general, the IURC Staff's White Paper properly reflects the status of the five federal standards as they pertain to the State of Indiana. The Commission has already considered or acted on many of the issues raised by EPA05 and for the most part its current practices already address the issues. For example, the Commission has already promulgated Net Metering rules and approved time-based metering offerings and is authorized to review power plant efficiency. Consequently, the review mandated by EPA05 should be able to be timely accomplished by acknowledging the status quo of these issues in Indiana.

**Net Metering and Interconnection**

The Company is in full agreement with the Commission's position that Net Metering and Interconnection has been recently implemented after a thorough review and no further consideration of EPA05 standards (11) and (15) is required.

## **Fuel Sources**

With regard to EPAct05 standard (12), Fuel Sources, or otherwise referred to as fuel diversity, adoption of standard (12) would require utilities to develop plans to minimize dependence on a single fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies. I&M recommends that the IURC find that it would be inappropriate and unnecessary to implement standard (12), Fuel Sources. Fuel diversity, in and of itself, is not an appropriate single objective, but instead is one of several objectives that are considered as fuel sources are analyzed. The AEP-East System and, in particular, I&M already plan generation to give due regard to fuel diversity, while concentrating on providing low cost generation to reliably and efficiently meet customer load. Utility systems are planned to consider an appropriate mix of capacity/fuel types ranging from base load generation, with higher capital cost but lower fuel cost, to peaking generation with lower capital cost but, typically, higher fuel cost. Evaluations of capacity and fuel type also consider the potential impacts associated with reliance on a particular fuel source (e.g. the possibility of interruption of electric supply to customers due to a fuel shortage or the risk of increased cost due to reliance on a single fuel). However, in large measure, economics dictate the fuels generally used to supply the various characteristics of an electric system's load.

The generating companies in the AEP System-East Zone, including I&M, own generation that uses a reasonably diverse mix of fuels. The table below shows the amount and proportion of capacity by fuel type for the AEP System-East Zone and I&M:

<u>AEP System-East Zone</u>			<u>Indiana Michigan Power Company</u>		
<u>Resource</u>	<u>Capacity (MW)#</u>	<u>Percent of Total</u>		<u>Capacity (MW)#</u>	<u>Percent of Total</u>
Nuclear	2,143	8.6	Nuclear	2,143	41.9
Coal	20,545	82.3	Coal	2,955*	57.8
Natural Gas	1,383	5.5	Natural Gas	0	0.0
Oil	3	0.0	Oil	0	0.0
Hydro	284	1.1	Hydro	15*	0.3
Pumped Storage	615	2.5	Pumped Storage	0	0.0

# Capacity is based on Net Maximum Capacity.

\* Coal capacity reflects I&M's ownership and purchase allocation of I&M's and AEP Generating Company's (AEG's) shares of Rockport (excludes unit power sales of I&M to Progress Energy and AEG to Kentucky Power Company). I&M's hydro units were re-rated effective January 2006.

In general terms, as the load served by the AEP System-East Zone grows, the proportion of capacity fueled by natural gas is also likely to grow if and as additional peaking capacity is added. While fuel diversity may increase overtime, the vast majority of the energy produced by the AEP System-East Zone will continue to be provided by low-cost nuclear and coal generation.

Renewable resources have the potential to become an efficient generation resource. In fact, AEP via it western fleet is a major wind producer in the United States. However, the cost of renewables is uncertain at this time and renewable resources generally cost more than conventional resources. Based upon preliminary reviews, the AEP System-East Zone has determined the following: 1) generally, wind and biomass can provide the most renewable generation for the least cost compared to other renewables; 2) landfill gas and solar can provide incremental distributed generation at higher costs than wind and biomass; 3) hydro upgrades can potentially provide incremental (renewable) generation at existing dams. Biomass as a boiler fuel seems to

be the renewable resource with the most potential for the AEP System-East Zone, but additional studies are required before any decision is made regarding such resources.

Indiana has reasonably secure access to many of the basic fuels and technologies that can generate electricity. Indiana has robust access to natural gas, coal, biomass, and refined petroleum as fuels. It has access to nuclear technology, wind technology, geothermal technology, hydropower technology, demand side reduction, and solar technology. However, it lacks access to economical resources of wind, geothermal, solar, and hydro power, so they have limited practical implementation.

To recap, the information provided above indicates that the AEP System-East Zone and I&M already use a diverse range of fuels and technologies to generate electricity. Although fuel diversity, in and of itself, should not be the primary goal, as costs change and technology develops the AEP System-East Zone and I&M will continue to evaluate alternative technologies and fuels, including renewable resource options, taking into consideration the associated risks and cost factors. In conclusion I&M does not believe that the IURC needs to implement standard (12), Fuel Sources.

### **Fossil Fuel Generation Efficiency**

Adoption of standard (13), Fossil Fuel Generation Efficiency, would require I&M to develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation. I&M and the AEP System-East Zone are committed to improving fossil fuel generation efficiency. As described below, there is sufficient incentive for I&M to seek improvements in fossil fuel generation efficiency. Correspondingly, we do not believe that it is necessary or beneficial to impose a 10-year plan to achieve this result. I&M recommends that the IURC find that it would be inappropriate and unnecessary to implement standard (13), Fossil Fuel Generation Efficiency.

AEP recognizes the economic need to improve fossil fuel generation efficiency, particularly to off-set the negative efficiency impact of new environmental controls being installed, as mentioned in the IURC Staff's White Paper. We strive to improve the operating performance of our generating units through prudent capital expenditures, the use of proven new technologies, efficient operation and careful planning. AEP has employed these concepts over time in the development and utilization of generation efficiency improvements to provide reliable, low cost electricity to its customers. Examples of AEP's notable accomplishments include:

- The development and operation of the first supercritical double reheat unit
- The development of a Sliding Pressure Technique for supercritical units to improve part load efficiency
- The installation of Advanced Design Steam Path to the System's larger units

In addition to still enjoying the benefits of these accomplishments, more recently, as part of a coordinated system-wide improvement program, AEP has focused on the utilization of tools to help it assess the efficiency of its plants. Examples of this include:

- The development of online performance monitors for plant operators
- The creation of a Heat Rate Deviation Calculation and Reporting tool that allows engineers and management to identify problem areas in major equipment
- The introduction of Facility Health Reports for outage planning and condition monitoring

From an operational perspective, processes exist to ensure proper long range and outage planning based on assessments of unit condition and operating liabilities that are conducted throughout the life of a unit. These assessments determine the timing and extent of predictive, preventative, and routine maintenance activities.

Decisions regarding significant capital investments are based upon engineering and economic assessments that take into consideration factors such as improved design technology and efficiency improvements.

Prudent actions of the facilities' operators and maintenance personnel also result in optimal performance. Their work activities are constantly reviewed for process improvement potential and identified deficiencies addressed as appropriate.

In addition, the Commission has authority to review power plant efficiency as necessary pursuant to its authority under IC8-1-2-48(c), which states: "[i]n carrying out its duties and powers under subsection (a) with regard to any utility which sells or generates electricity, the commission may also inquire into or audit a utility's powerplant efficiency and system reliability." Accordingly, there is no need for the Commission to create additional regulatory requirements by mandating the creation of a 10 year plan, as posited by EAct05 standard 13, because the Company has positioned itself for continuous improvement in this area, which is subject to inquiry and audit if found necessary by the Commission.

In summary, I&M believes that the IURC is not required nor has any need to implement EAct05 standard 13. The Company has demonstrated its leadership in efficiency improvements through innovations such as those cited above and positioned itself for future improvements through the implementation of a coordinated, disciplined approach to a sustainable system-wide improvement program as described in the responses to the data requests. This has all been accomplished, without such a requirement, and, in fact, the ability to achieve the improvements has been possible because of the flexibility from rigid requirements.

### **Time-Based Metering and Communications**

Adoption of standard (14), Time-based Metering and Communications, would require I&M to offer each of its customer classes, and provide individual customers upon request, a time-based rate schedule. This time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

I&M believes that the IURC should not require any further action on the behalf of I&M to implement the time-based metering and communications standards set out in the federal EAct05 at this time.

I&M currently offers a variety of optional time-based tariffs as well as several load management options designed to encourage customers to reduce on-peak usage. Optional time-of-use tariff provisions are available to all of I&M's customer classes. These options are available to customers pursuant to existing Commission authority.

The use of advanced metering and communications technology can provide customers an opportunity to reduce costs and/or use their energy more efficiently and wisely. Across the AEP System, many larger customers participate in these programs today, by closely monitoring on- and off-peak demand and by controlling their loads to ensure that a pre-determined demand is not exceeded during demand billing intervals. Where these systems are used, decisions are driven by costs and benefits. For some customers, energy costs are a major portion of production costs and have a significant effect on profitability, so motivation exists to pursue demand response options.

From the Company's perspective, the decision by customers to participate in time-based tariff offerings will ultimately be based on cost. But, it is unclear at what price small usage retail customers will be willing to change their usage patterns, or to take actions such as to program water heaters and similar equipment. As a result, the

Company does not believe that demand response and time-based metering options will come into widespread use until 1) energy and capacity prices rise to the point of providing the customer with the opportunity for significant savings, and 2) investment costs are sufficiently low to make the cost-benefit calculation significantly beneficial to the consumer.

While the Company's current optional tariff offerings to small usage customers include time-based rate provisions, they do not generally include advanced metering and communications technology. Based upon customer response to I&M's current tariff offerings, it is apparent that, at the current price level of the Company's rates, customers have decided that the economic rewards associated with participating in the various time-based programs do not outweigh the inconvenience or cost associated with changing their usage characteristics. It would not make sense, at this time, to require the Company to offer to its small usage customers even more complex and expensive advanced metering offerings in addition to current time-of-use tariff provisions. Any further action on this matter would not appear to be beneficial to the customers of I&M.

Any decision by the Commission to require utilities to offer additional time-of-day or advanced metering and communications technology should include full recovery of all utility program cost expenditures. Should the Commission mandate the installation of time-of-use metering or advanced metering and communications systems for all Indiana customers, the costs would be significant.

I&M has not requested volume meter pricing for its entire customer base in Indiana, however, an estimate by the Company to provide simple time-of-use metering for all its customers would be in the range of \$100 to \$150 per customer. It should be noted that the meter costs are a small portion of the two way communications necessary to support critical pricing. The communication infrastructure costs may in and of itself

prove cost prohibitive. With I&M's Indiana jurisdictional base of more than 450,000 customers, total costs could quickly become very significant. Of more importance though, is whether customers would utilize the meters to control energy costs even if the meters were mandated. The Company does not believe that the cost of metering is the driving impediment to customer participation in demand response programs. While such costs will improve increasing scale and scope, customers' participation will be driven by cost-benefit considerations. As mentioned previously, I&M firmly believes that when prices become high enough, customers will invest in and use technology to realize the savings available.

In summary, I&M supports the use of time-based metering and communications systems for those (typically large) customers that want to take advantage of the Company's tariff offerings on time-of-use rates. When the demand for such services increases, I&M will stand ready to meet its customer's needs. Experience shows that such options can be made available to customers pursuant to existing Commission authority. Requirements by the IURC for the creation of tariffs or the provision of meter or communications technology are not warranted.

### **CONCLUSION**

I&M submits these comments and recommends that the Commission determine that the State has complied with the requirement to consider or investigate implementation of the federal standards and decline to adopt the federal standards having found that comparable standards have been implemented by the State. However, to the extent the Commission finds that workshops or docketed proceedings are necessary in this matter, I&M would plan to participate.

**ENERGY POLICY ACT 2005:**  
**SUGGESTED STANDARDS FOR STATE CONSIDERATION**  
**DATA REQUEST RESPONSES OF**  
**INDIANA MICHIGAN POWER COMPANY**

**I. Fuel Sources**

**Amendments to PURPA; Sec. 1251; amending 16 USC 2621(d) by adding (12) –  
Fuel Sources**

"Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies."

**1) Do the Indiana Integrated Resource Plan and Certificate of Need processes provide for a sufficient method to insure that utilities develop a plan to minimize dependence on one fuel source? Please explain.**

**Response**

Yes, the Integrated Resource Plan rules encourage the use of renewable resources by stating in Section 8(4) that the resource plan should utilize, to the extent practical, all economical load management, conservation, non-conventional technology relying on renewable resources, cogeneration, and energy efficiency improvements as sources of new supply. On the other hand, Section 8(6) says the plan must demonstrate that the most economical source of supply-side resources has been included in the integrated resource plan. The latter rule can be reconciled with a goal of fuel diversity to the extent that (a) the economic mix of generation to meet base load and peaking requirements relies on more than one fuel and (b) the evaluation of supply resources takes into account risks associated with fuel supply and fuel cost.

The Certificate of Need process also contributes to the consideration of dependence on one fuel source. Section 4 states that "In acting upon any petition...the commission shall take into account...other methods for providing...service, including...renewable energy sources."

**2) How could the IURC best ensure that the electric energy sold to consumers is generated using a diverse range of fuels and technologies, including renewable technologies?**

**Response**

Please see the responses to questions 1 and 4. I&M does not believe it is necessary for the IURC to take any further action to ensure that the electric energy sold to consumers is generated using a diverse range of fuels.

**3) Is the requirement of IC 8-1-2-42(d)(1) compatible with a requirement to ensure the electric energy a utility sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies? Would summary FAC proceedings provide for timely review if such a requirement were implemented? Please explain.**

**Response**

In I&M's case, IC 8-1-2-42(d)(1) would appear to be consistent with an objective of fuel diversity. IC 8-1-2-42(d) (1) states,

The commission shall conduct a formal hearing solely on the fuel cost charge requested in the petition subject to the notice requirements of IC 8-1-1-8 and shall grant the electric utility the requested fuel cost charge if it finds that:

(1) the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;

IC 8-1-2-42(d)(1) speaks to the economic dispatch of available resources for the purpose of fuel cost recovery. Using I&M as an example, its hydro and nuclear units are base loaded for native load customers. Lower cost coal units are dispatched for native load, with higher cost coal generation assigned to off-System sales. I&M's owned generation would be supplemented with economic purchases of natural gas- or coal-fired generation or other resources as available from the market.

The statute would also appear to be consistent with a goal of fostering renewable technologies, in that certain renewables such as hydro, wind, and solar, have low (or no) fuel cost. IC 8-1-2-42(d)(1) standing alone, however, is insufficient to promote the expansion of utility use of renewable technologies. In general, renewables would be considered to have low (or no) variable costs, but high fixed costs. To foster utility development and construction of renewable technologies, utilities will require comfort through the IC 8-1-8.5 process and assurance of the recovery of high fixed cost investments and the incentives identified in IC 8-1-8.8-11.

Promoting utility purchases of renewable resources would require the Indiana Legislature to remove the impediment of IC 8-1-2-42(d) that states "When such [fuel charge] application is filed the petitioning utility shall show to the commission its cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity..." Limiting timely recovery to "the cost of fuel included in the cost of purchased electricity" excludes the high fixed costs associated with renewable energy purchases and serves as an impediment to the expansion of renewable technologies. The full cost of utility power purchases, deemed prudently incurred through summary FAC review, should be recoverable by utilities in a timely manner to further promote fuel and technological diversity.

**4) Does today's energy market environment provide sufficient incentive for utilities to diversify their fuel sources? Please explain.**

**Response**

Yes. Managing the costs of fuel used to generate electricity in today's energy market requires a utility to be cognizant of the volatility and availability of fuel resources. Accordingly, a utility must strike an appropriate balance as to the types of fuels in its energy portfolio so that its costs are as low as reasonably possible. In Indiana, those costs are reviewed in a fuel adjustment case and have generally been approved, which indicates that sufficient incentives exist to achieve a reasonable degree of diversity. If additional diversity is demanded just for the sake of moving above and beyond this point of equilibrium, incentives in the form of risk premiums and cost recovery assurances would be needed to evoke this behavioral response.

Today's national and state regulatory framework provides freedom for new entrants to bring generation resources into the market and connect to the transmission grid. The market, operating unconstrained by political or societal objectives, will provide long run balance between lowest achievable cost to consumers and highest potential profit to producers. When constraints begin to be added, regardless of how reasonable or laudable, the new objectives inherently begin to conflict with one another, so a compromised objective influences the pure financial outcome of the unfettered market. Examples of these constraints are required reserve margins for reliability, emission retrofitting of existing units, and tax credits for wind generation. These types of constraints on the market serve their intended purposes and therefore are generally accepted by society and market participants.

Indiana has reasonably secure access to many of the basic fuels and technologies that can generate electricity, so it exists in an environment where the market does provide sufficient incentive to diversify fuel sources. Indiana has robust access to natural gas, coal, biomass, and refined petroleum as fuels. It has access to nuclear technology, wind technology, geothermal technology, hydropower technology, demand side reduction, and solar technology. However, it lacks access to economical resources of wind, geothermal, solar, and hydro, so they have limited practical implementation. Within its physical limitations, the market has sufficient incentives to achieve fuel diversity as a byproduct of the efficiently functioning market.

## **II. Fossil Fuel Generation Efficiency**

### **Amendments to PURPA; Sec. 1251; amending 16 USC 2621(d) by adding (13) – Fossil Fuel Generation Efficiency**

"Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation."

**1) What, if any, specific plans has your utility put in place to drive increased fossil fuel generation efficiency? How do these plans differ from what was done in the past? How do you expect these plans to change over the next ten years?**

#### **Response**

In late 2003, under the sponsorship of the AEP Generation Assets group, the Generation Performance Team (GPT) was formed to develop a sustainable program for improvement of the AEP System heat rate and to provide guidance for a coordinated, disciplined approach to a system-wide performance improvement. The Team consists of representatives from the Plants and region and central engineering (Plant Engineering & Engineering Services).

The GPT established a network of Plant Heat Rate Champions to serve as a focal point for performance improvement initiatives and other heat rate related activities in the plants. The GPT and Region Heat Rate Champions coordinate heat rate related activities on a regional basis.

Consistent with its mission, the GPT has focused on long term improvements in several areas:

- Developing tools to assist the Plant Heat Rate Champions in identifying, analyzing and correcting heat rate problems. Examples: Heat Rate Deviation Report (HRDR), On-Line monitor screens for operators
- Influencing Corporate Culture to reflect the significant role heat rate is starting to play in AEP's, and therefore the customer's, cost to meet environmental regulations and to maintain the proper balance of engineering and maintenance resources allocated to heat rate improvement and other activities. The Communication examples cited below also apply to Influencing Corporate Culture
- Improving Interplant Communications to share experiences and exchange ideas. Examples: Generation Performance Forum, *Heat Rate Monitor* Newsletter, Monthly Regional Conference Calls with Plant Champions to achieve a higher visibility and interest in heat rate improvement
- Providing specialized heat rate training in response to identified needs. This is in addition to standardized training currently available to plant operators. Plans are underway to develop a more proactive program approach specifically for heat rate

The initial success of this approach is in large part due to the GPT's ability to adapt the heat rate improvement program to rapidly changing conditions and requirements while maintaining a long term view. Based on this success, no change is anticipated in the

team concept over the next ten years but the program put in place by the team is expected to be continually improved and adapted to the changing conditions.

Further, action by the IURC with regard to Fossil Fuel Generation Efficiency would not appear necessary as the Indiana Legislature has granted jurisdiction and authority in this area to the Commission in the form of IC 8-1-2-48(c), which states:

In carrying out its duties and powers under subsection (a) with regard to any utility which sells or generates electricity, the commission may also inquire into or audit a utility's powerplant efficiency and system reliability.

**2) Does today's energy market environment provide sufficient incentive for utilities to increase the efficiency of its fossil fuel generation? Please explain.**

**Response**

Yes, today's energy market environment provides sufficient incentive and AEP recognizes the economic need to improve fossil fuel generation efficiency. As described under Question Number 1 of this section, AEP has a sustainable program in place actively focusing on heat rate improvement for the AEP System. AEP strives to improve the operating performance of our generating units through wise capital expenditures, the use of proven new technologies, efficient operation and careful planning. AEP has employed these concepts over time in the development and utilization of generation efficiency improvements to provide reliable, low cost electricity to its customers.

**3) Provide the historical annual operating efficiencies for the past 10-years for each of your fossil fuel generation plants and a similar cumulative value for your utility.**

**Response**

The table below provides a 10-year history of annual operating efficiencies for I&M-operated fossil fuel generation plants. Additionally, there are cumulative values listed at the bottom of this table.

**I&M Operated Coal-Fired Plants  
10-Year Heat Rate History**

		>>>> Net Heat Rate - Btu/kWh									
Plant	NMC-MW	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Rockport	2600	10051	9952	9852	9776	9816	9740	9807	9764	9727	9654
Tanners Creek	995	9835	9840	10091	9922	9948	10021	10060	10201	10023	10319
<b>I&amp;M Operated Coal-fired Total</b>	<b>3595</b>	10002	9924	9902	9814	9848	9803	9873	9865	9803	9799

Notes: NMC-MW equals Net Maximum Capacity in Megawatts. Rockport capacity as shown reflects the total I&M-operated capacity (the I&M and AEP Generating Company ownership shares) of Rockport Plant.

The slight decline in heat rate efficiency of the Tanners Creek Plant has been influenced by environmental and fuel issues such as low NOx burners and the introduction of western Powder River Basin coal.

### **III. Smart Metering**

#### **Amendments to PURPA; SEC. 1252. Amending 16 U.S.C. 2621(d) by adding (14) – Time-based Metering and Communications-**

(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others-

- (i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

- (ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

- (iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

- (iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.

(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 11 5(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).

**1) Please describe the present status of time-based metering and communications within your customer base. Include detail by customer class (e.g. residential, commercial, industrial) relating to tariff offerings, smart meters deployed, means of communicating collected data with participating customers, and capital invested in infrastructure.**

**Response**

The Company has tariff offerings that utilize time-based metering available to all customer classes. Please see Attachment 1, which contains a description of the Company's available time-based metering and demand response tariff provisions along with current customer participation in these programs. The Company currently employs interval data meters for all 251 Tariff QP, Tariff IP and Tariff CS-IRP customers, as well as for a representative sample across all other classes. The costs of these revenue and statistical meters are included in the Company's embedded cost rates. Two-way communication between the Company and customers participating in I&M's interruptible programs is not accomplished through the meter, but through the Company's Customer Communication System. That system communicates information over the internet, through paging, through e-mail and in some instances through remote terminal units. Interval meter data is not communicated as part of the Customer Communication System.

Upon request and if available, the Company provides pulse data from its metering to customers and will also provide interval data. The costs of such services are paid by those using the service.

**2) Describe the methods utilized presently or historically to communicate tariff/program opportunities to customers. Do you have plans to enhance marketing of these opportunities? Please explain.**

**Response**

The Company makes its tariffs available on its website for all customers to investigate its tariff and program offerings. Customers can also call into the Customer Solutions Centers to speak with Company representatives concerning available tariffs and offerings. Billing inserts and/or notices have also been used to inform customers of new tariff offerings. Larger commercial and industrial customers have specific Company representatives assigned to them to assist them in investigating all opportunities that the Company offers. The Company does not currently plan to further enhance its marketing of these opportunities.

**3) Detail any cost/benefit studies conducted for your service area regarding time-based metering communication deployment and tariffs. Detail should at a minimum include cost and demand response assumptions.**

**Response**

The Company has not conducted cost/benefit studies regarding time-based metering communication deployment and tariffs.

**4) Detail the response to any customer surveys you may have conducted in your service area regarding time-based metering and rates. If no surveys have been conducted, what customer input method does your utility employ to evaluate customer demand for time-based metering and rate offerings?**

**Response**

Perhaps the single-best indicator of customer demand for existing time-based metering and rate offerings is current customer participation levels. As can be seen in I&M's Attachment 1, with the exception of the residential storage/load-management water heating provision, customer participation has not been significant. It appears that customers are either unwilling or unable to modify their usage of electricity to achieve the potential savings available under I&M's current offerings. One major factor contributing to this level of response is the relative low price of electricity in I&M's service territory.

**5) What, if any, regulatory barriers exist which limit the expansion of time-based metering and rates?**

**Response**

The Company does not perceive any regulatory barriers for the provision of time-based rates. I&M currently provides a wide array of time-based rate provisions as shown in I&M's Attachment 1. The potential market barriers to implementing mass-scale time-based metering include uncertainty of cost recovery, lag in cost recovery, lack of cost effective technologies, lack of customer understanding/education, and relatively low electric rates. However, with the Company's current array of rate provisions and the capabilities provided with existing meter options, there does not appear to be a need for additional smart metering standards for Indiana. I&M has made these provisions available to customers under existing authority of the Commission and would presume that other utilities under the Commission's jurisdiction have done or could do the same.

**6) Can time-of-use rates be effectively implemented without the use of smart metering? Please describe any new or expansion of existing time-of-use rates your utility plans to implement in the next 24 months.**

**Response**

All of the time-of-use tariff offerings shown in Attachment 1 to the Company's Response to Question 1, above, can be accomplished through the use of standard time-of-use or interval data meters. The Company has no specific plans at this time to expand its existing time-of-use rate offerings, or introduce any new offerings, in the next 24 months.

**Indiana Michigan Power Company - Indiana**  
**Time-based Metering/Demand Response Tariff Provisions**  
**March 2006**

Attachment 1

<u><b>Tariff/Rider</b></u>	<u><b>Description of Service/Provision</b></u>	<u><b>Customer Participation</b></u>
<b><u>Residential</u></b>		
Tariff RS	Storage/load management water heating	16,439
Tariff RS-OPES	Off-peak energy storage	831
Tariff RS-TOD	Time-of-day	751
<b><u>Commercial &amp; Industrial</u></b>		
Tariff SGS	Load management time-of-day	50
Tariff MGS	Load management time-of-day	115
Tariff MGS-TOD	Time-of-day	794
Tariff LGS	Load management time-of-day Off-peak hour provision	25 *
Tariff QP	Off-peak hour provision	*
Tariff IP	Off-peak hour provision	*
Tariff WSS	Time-of-day	3
Tariff CS-IRP	Interruptible	7
Rider ECS	Emergency curtailable	0
Rider PCS	Price curtailable	0

\* All customers on Tariffs LGS, QP and IP are eligible to participate in the off-peak hour provision. The number of customers utilizing this provision is not readily available.

**Service Description**

**Storage/load management water heating** - Available to customers who install a Company approved water heating system which consumes electrical energy during off-peak hours and stores hot water for use during on-peak hours. Customer receives reduced energy charge for fixed block of monthly kWh.

**Off-peak energy storage/Load management time-of-day** - Available to customers who use energy-storage devices with time-differentiated load characteristics that consume energy only during off-peak hours and store energy for use during on-peak hours. Customer is served under time-of-day energy charges

**Time-of-day** - Optional tariff for customers that are capable and willing to consume electrical energy primarily during the Company's designated off-peak period to take advantage of the price differential between on-peak and off-peak energy rates

**Off-peak hour provision** - Optional tariff provision whereby demand created during off-peak hours is disregarded for billing purposes provided that the monthly billing demand shall not be less than 60 percent of the maximum demand created during the billing month.

**Interruptible/ECS/PCS** - Available to customers that are willing to reduce load upon request by the Company. Customer either receives a reduced demand charge or a payment for amounts reduced.